

PROPOSED

Significant Modification to a Covered Source Review Summary

Application File No.: 0088-09

Permit No.: 0088-01-C

Applicant: Chevron USA Products Company

Facility Title: Chevron Hawaii Refinery
Located at 91-480 Malakole Street, Kapolei, Oahu

Mailing Address: Chevron USA Products Company
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Kapolei, HI 96707

Responsible Official: Mr. David E. Rogers
Refinery Manager
(808) 682-5711

Point of Contact: Ms. Helen Mary Wessel
Environmental Specialists
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Application Date: Significant Modification application dated February 23, 2006 and additional information dated March 24, 2006 and April 7, 2006

Proposed Project:

SICC 2911 (Petroleum Refining)

Significant Modification dated February 23, 2006

In accordance with the Chevron Consent Decree Section I, Flaring Devices - NSPS applicability, the Hawaii Refinery is required to comply with 40 CFR 60 Subparts A and J. In order to comply with the Consent Decree, the refinery will install flare vapor recovery system on the Fluid Catalytic Cracking Unit (FCC) Flare and move several pressure safety valves and flare sources from the Crude Flare to the FCC Flare to make it a sweet flare (below 160 ppm H₂S). They will also install a Continuous Emissions Monitoring System for H₂S on the Crude Flare to ensure the requirements specified in 40 CFR §60.104(a)(1) are met. The overall project will allow the flare systems to operate reliably while recovering routine flare gas volumes from the FCC Flare. The project is to be constructed in October 2006 to meet the Consent Decree required certification date of December 31, 2006, for both the FCC and Crude Flares. An application fee of \$1,000.00 for a significant modification was submitted by the applicant and processed.

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Additional information dated March 24, 2006

In this letter Chevron requested to decouple the NSPS Subpart J - Standards of Performance for Petroleum Refineries requirements from the Flare Vapor Recovery System Project to expedite the permit review process. This is possible because there is nothing in the project itself that triggers the applicability of NSPS Subpart J. The only applicable Federal regulations are NSPS Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries and NSPS Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems. The acceptance of NSPS Subpart J for the flares was necessary only to meet the future Consent Decree requirements. As such, the installation of the H₂S CEMS will be postponed until NSPS Subpart J is applicable, although the moving of sources from the Crude Flare to the FCC Flare will lower the H₂S below 160 ppm.

Equipment Description:

FCC Flare Vapor Recovery System

The routine streams in the Crude and FCC Flares were identified by Refinery Operations and Engineering. The routine sour gas streams, which contain H₂S, in the Crude Flare System will be rerouted to the FCC Flare System to be normally recovered. This will make the operation of the Crude Flare System sweet with H₂S concentrations less than 160 ppm. This modification will allow the Crude Flare to burn a small routine gas flow that will emit little sulfur dioxide (SO₂).

The new FCC Flare Vapor Recovery System will be sized to handle the routine FCC Flare gas volumes and deliver the recovered flare gas to the wet gas compressor inlet in the FCC. The FCC Flare Vapor Recovery System will be connected to the FCC Flare header and pull suction from it. The recovered gas is returned to the FCC wet gas compressor and processed in the gas recovery section of the FCC. In the FCC, the gas is separated into various process streams or fuel gas. It is ultimately sweetened in an amine contactor prior to being returned to the appropriate unit process columns with the refinery.

The FCC Flare header pressure is normally 0 to 1.5 psig and must be maintained at this level for the flare system to function as an emergency safety device and not interfere with other process' operation.

Every three to five years, the FCC wet gas compressor will be out of service for short durations. During these wet gas compressor outages, the recovered flare gas from the FCC Flare Vapor Recovery System will be treated in a caustic (NaOH) scrubber before being added to the fuel gas mix drum. Delivery of the recovered flare gas to the caustic scrubbers will require a higher discharge pressure for the FCC Flare Vapor Recovery System.

The FCC Flare Vapor Recovery System consists of two 50,000 SCFH liquid ring compressors, two knockout drums with pumps, one separator, fin fan coolers, seal flush system, and other ancillary equipment.

A single liquid ring compressor will be used when the recovered flare gas is being directed to the FCC wet gas compressor. When the recovered flare gas is required to be routed to the caustic scrubber, two liquid ring compressors will be used due to the higher discharge pressures required. The ancillary equipment associated with delivering the recovered flare gas to the caustic scrubber is a chiller and a phase separator.

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The centrifugal blower capacity will be designed to recover normal routine gas flow from the FCC Flare header and up to 100,000 SCFH. Each compressor has the capacity to handle the normal routine gas flow from the FCC flare header. The second compressor can be brought on line when the first compressor is down for preventative maintenance or during upset conditions when the gas flow exceeds 50,000 SCFH up to a maximum recovery of 100,000 SCFH.

H₂S Flow Meters

Chevron has installed a flow meter in each of the Flare Systems. The flow meters will continue to be used from recording flow to each flare.

Applicable Requirements:

Hawaii Administrative Rules (HAR)

Title 11, Chapter 59	Ambient Air Quality Standards
Title 11, Chapter 60.1	Air Pollution Control
Subchapter 1	General Requirements
Subchapter 2	General Prohibition
HAR 11-60.1-31	Applicability
Subchapter 5	Covered Sources
Subchapter 6	Fees for Covered Sources, Noncovered Sources, and Agricultural Burning
HAR 11-60.1-111	Definitions
HAR 11-60.1-112	General Fee Provisions for Covered Sources
HAR 11-60.1-113	Application Fees for Covered Sources
HAR 11-60.1-114	Annual Fees for Covered Sources
HAR 11-60.1-115	Basis of Annual Fees for Covered Sources
Subchapter 8	Standards of Performance for Stationary Sources

Federal Requirements

40 CFR Part 60 - Standards of Performance for New Stationary Sources (NSPS)
Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries
Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems

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Non-Applicable Requirements:

Hawaii Administrative Rules (HAR)

Title 11, Chapter 60.1 Air Pollution Control
 Subchapter 7 Prevention of Significant Deterioration
 Subchapter 9 Hazardous Air Pollutant Sources
 HAR 11.60.1-174 Maximum Achievable Control Technology (MACT)
 Emission Standards

Federal Requirements

40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants (NESHAPS)

40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants for Source Categories (Maximum Achievable Control Technologies (MACT) Standards)

 Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries

Reason: Subpart CC, i.e. 40 CFR §63.640, is not applicable to the FCC Flare Vapor Recovery System (VRS) because the HAPS content of the flare gas is less than 5% by weight per 40 CFR §63.640(d)(3).

New Source Performance Standards (NSPS):

The FCC Flare Vapor Recovery System will be subject to NSPS Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries and NSPS Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems.

Best Available Control Technology (BACT):

A Best Available Control Technology (BACT) analysis is not applicable since there is no net emissions increase from the proposed modification. There will be a net emissions reduction of NO_x, SO₂, CO, PM/PM₁₀ and VOC as a result of the project.

Prevention of Significant Deterioration (PSD):

This significant modification is not subject to PSD review as the modification is not considered a *major modification* to a major stationary source as defined in HAR §11-60.1-131.

Consolidated Emissions Reporting Rule (CERR):

40 CFR Part 51, Subpart A - Emission Inventory Reporting Requirements, determines CER based on the emissions of criteria air pollutants from Type A and Type B point sources (as defined in 40 CFR Part 51, Subpart A), that emit at the CER triggering levels as shown in the table below.

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Pollutant	Type A CER Triggering Levels ^{1,2} (tpy)	Type B CER Triggering Levels ¹ (tpy)	Pollutant	In-house Total Facility Triggering Levels ³ (tpy)	Project Emissions ³ (tpy)
NO _x	≥2500	≥100	NO _x	≥25	-148.0
SO _x	≥2500	≥100	SO _x	≥25	-210.8
CO	≥2500	≥1000	CO	≥25	-33.6
PM ₁₀	≥250	≥100	PM/PM ₁₀	≥25	0
VOC	≥250	≥100	VOC	≥25	-1.2
Pb		≥5	HAPS	≥5	0

¹ Based on actual emissions

² Type A sources are a subset of Type B sources are the larger emitting sources by pollutant

³ Based on potential emissions

There is no change from Covered Source Permit No. 0088-01-C. This Type A facility emits above the Type A (for SO₂) CER and in-house triggering levels. Therefore, CER and in-house reporting requirements are applicable.

Compliance Data System (CDS):

No change from Covered Source Permit No. 0088-01-C.

Compliance Assurance Monitoring (CAM):

No change from Covered Source Permit No. 0088-01-C.

Synthetic Minor Source:

No change from Covered Source Permit No. 0088-01-C.

Insignificant Activities:

No change from Covered Source Permit No. 0088-01-C.

Alternate Operating Scenarios:

No change from Covered Source Permit No. 0088-01-C.

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Project Emissions:

Emission Calculations

Annual emission estimates for the FCC Flare and Crude Flare were calculated by applying AP-42 emission factors for each criteria pollutant to the annual refinery crude throughput. No emissions were estimated for particulate matter (PM/PM₁₀) or Sulfuric Acid Mist (H₂SO₄). Based upon the AP-42 emission factors for refinery feed, PM emissions are considered negligible. The operating temperatures of the flares are in excess of the temperature conditions under which H₂SO₄ can be formed. Therefore, PM and H₂SO₄ emissions are not presented.

The Baseline Actual Emissions represent an average annual emissions estimate developed from a consecutive 24-month period within the past 10 years of refinery operation. The 24-month time period from January 2001 to December 2002 was determined to be most representative of normal operations. Therefore, the average annual crude throughput for 2001 and 2002 was used to determine the baseline actual emissions. The emissions attributed to each flare was based on a percentage of gas flow rate to each flare. Recent flow meter data was used to determine the percentage of gas flow to each flare. Each flare's gas flow percentage was applied to the annual crude throughput based emissions to determine the amount attributable to each flare.

The Projected Actual Emissions are based on an annual crude throughput estimate developed from refinery crude throughput projected over a five-year period extending from 2006 to 2010. Each successive yearly crude throughput was estimated to experience a 5% annual increase until it reached a maximum throughput of 23,725,000 bbls/yr or 65,000 bpd. The average annual throughput over that the next five years was 22,724,000 bbls/yr or 62,230 bpd. The flow rate percentage determined from recent flare flow meter data was applied to the projected annual crude throughput to determine the projected actual emissions for the Crude Flare. Since the FCC Flare Vapor Recovery System will recover all normal gas flow to the FCC Flare, the only projected actual emissions attributed to the FCC Flare will be from refinery fuel gas (RFG) used to maintain the flare pilot burner.

The project's net emission changes were developed by subtracting the baseline actual emissions from the potential emissions estimates. Potential emissions were based on a maximum refinery feed rate of 23,725,000 bbls/yr or 65,000 bpd. The net emission changes resulting from the proposed modifications to the existing equipment were all found to be below the PSD significant emission thresholds.

Nitrogen Oxides, Carbon Monoxide, and Sulfur Dioxide Emissions

A reduction in emissions for each of these pollutants will result from the installation of the FCC Flare Vapor Recovery System and the rerouting of some of the sour process vents currently feeding the Crude Flare.

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Volatile Organic Compounds Emissions

VOC emissions are formed by combustion associated with operation of the flares and by fugitive emissions escaping from leaking piping components such as flanges, valves, and compressor seals. Projected Actual VOC emissions due to combustion are expected to experience a decrease. The total Projected Actual VOC emissions will also experience a net emissions decrease even with the additional fugitive VOC emissions resulting from the piping components associated with the FCC Flare Vapor Recovery System included.

VOC fugitive emission estimates were developed using EPA Correlation Equation Factors for refinery piping components (see EPA's Protocol for Equipment Leak Emission Estimates, Table 2-10. Petroleum Industry Leak Rate/Screening Value Correlations, dated 11/95). VOC emissions estimates for the foul water tanks in the Effluent Plant were also developed. The tanks will be vented through an activated carbon unit designed to effectively remove VOCs and H₂S prior to being released to atmosphere.

Hazardous Air Pollutants Emissions

HAP emissions from the flares consist solely of 1,3 - Butadiene, which has been identified as a component in the butane. The portion not destroyed in the combustion process is released as a HAP. A decrease of HAP emissions is expected.

Crude Flare Emissions

The gas flow rates to each of the refinery flares stacks are currently metered and recorded. Emission calculations for each flare were based upon the percentage of gas flowing to each flare. The gas flow rate percentage for each flare was applied to the annual refinery crude throughput for calculating separate emissions attributable to each flare. The same calculated percentage split was used for developing both the Baseline Actual and Projected Actual emissions for both flares.

Although the routine sour process vents currently running to the Crude Flare will be diverted to the FCC vapor recovery compressor, the SO₂, NO_x, CO and VOC emissions from the Crude Flare will still increase assuming the 5% crude throughput growth rate. The anticipated annual increase of crude throughput directly results in an increase in estimated emissions from the Crude Flare.

FCC Flare Emissions

The routine process gas streams currently flowing to the FCC Flare will be diverted to the FCC Flare Vapor Recovery System. The removal of the routine process gas streams to the FCC Flare during normal operations will result in the FCC Flare emissions produced solely from pilot gas combustion of the Flare burners. The post-projected actual FCC Flare SO₂, NO_x, and CO emissions are based on pilot gas combustion burning RFG. The VOC emissions are mainly attributed to the fugitive VOC emission from the new Flare Vapor Recovery System components. The projected SO₂ emissions for the FCC flare were calculated using an emission factor developed from the H₂S limit of 160 ppm in the fuel gas.

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Baseline Actual Emissions

Source	Pollutant	Emission Factor ¹ (lb/1000 bbl)	Baseline Actual Emissions ^{2, 3, 4} (tpy)	Baseline Actual Total Emissions ⁶ (tpy)
Crude Flare	NO _x	18.9	23.95	
	SO ₂	26.9	34.09	
	PM	0	0	
	PM ₁₀	0	0	
	CO	4.3	5.45	
	VOC _{combustion}	0.8	1.01	
	H ₂ SO ₄ Mist	0	0	
	HAPs		0.0002	
FCC Flare	NO _x	18.9	154.28	178.23
	SO ₂	26.9	219.58	253.67
	PM	0	0	0
	PM ₁₀	0	0	0
	CO	4.3	35.1	40.55
	VOC _{combustion}	0.8	6.53	7.54
	H ₂ SO ₄ Mist	0 ⁵	0	0
	HAPs		0.0013	0.0015

¹ Based on AP-42 Emission Factors (1/95) for Petroleum Refining, Table 5.1-1

² Based on a baseline actual refinery feed rate of 18,860,300 bbl/yr

³ Based on a Crude Flare gas flow rate of 13.44%

⁴ Based on a FCC Flare gas flow rate of 86.56%

⁵ Combustion temperature prevents formation of H₂SO₄ mist

⁶ Sum of Crude Flare and FCC Flare emissions

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Projected Actual Emissions

Source	Pollutant	Emission Factor	Projected Actual Emissions (tpy)	Projected Actual Total Emissions ¹¹ (tpy)
Crude Flare	NO _x	18.9 ^{1, 3}	28.86 ^{5, 6}	
	SO ₂	26.9 ^{1, 3}	41.08 ^{5, 6}	
	PM	0	0	
	PM ₁₀	0	0	
	CO	4.3 ^{1, 3}	6.57 ^{5, 6}	
	VOC _{combustion}	0.8 ^{1, 3}	1.22 ^{5, 6}	
	H ₂ SO ₄ Mist	0	0	
	HAPs		0	
FCC Flare	NO _x	100 ^{2, 4}	0.07 ⁷	28.93
	SO ₂	27.02 ^{4, 8}	0.02 ⁷	41.1
	PM	0	0	0
	PM ₁₀	0	0	0
	CO	84 ^{2, 4}	0.06 ⁷	6.62
	VOC _{combustion}	5.5 ^{2, 4}	0.004 ⁷	
	VOC _{fugitive}		3.55 ⁹	
	VOC _{total}		3.56	6.0
	H ₂ SO ₄ Mist	0 ¹⁰	0	0
	HAPs		0	0
Foul Water Tanks	VOC		1.21	

¹ Based on AP-42 Emission Factors (1/95) for Petroleum Refining, Table 5.1-1

² Based on AP-42 Emission Factors (7/98) for Natural Gas Combustion, Tables 1.4-1 and 1.4-2

³ Units in lb/1000 bbl

⁴ Units in lb/mmscf

⁵ Based on a projected actual refinery feed rate of 22,724,200 bbl/yr

⁶ Based on a Crude Flare gas flow rate of 13.44%

⁷ Based on a FCC Flare - Pilot: RFG flowrate of 150 scf/hr @ 8,760 hrs/yr

⁸ Based on 160 ppm H₂S for the SO₂ emission factor, lb SO₂/mmscf = 1/379 * 160 ppm S * 64 = 27.02 lb/mmscf

⁹ Based on EPA's Protocol for Equipment Leak Emission Estimates, Table 2-10. Petroleum Industry Leak Rate/Screening Value Correlations, 11/95

¹⁰ Combustion temperature prevents formation of H₂SO₄ mist

¹¹ Sum of Crude Flare and FCC Flare emissions

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Emissions Summary

Pollutant	Potential Emissions ¹ (tpy)	Projected Actual Emissions (tpy)	Baseline Actual Emissions (tpy)	Net Emissions Change ² (tpy)	Net Emissions Change ³ (tpy)	Significant Level (tpy)
NO _x	30.2	28.9	178.2	- 148.0	- 149.3	40
SO ₂	42.9	41.1	253.7	- 210.8	- 212.6	40
PM	0	0	0	0	0	25
PM ₁₀	0	0	0	0	0	15
CO	6.9	6.6	40.5	- 33.6	- 33.9	100
VOC	6.3	6.0	7.5	- 1.2	- 1.6	40
H ₂ SO ₄ Mist	0	0	0	0	0	7
HAPs	0	0	0.0015	- 0.0015	- 0.0015	

¹ Based on a potential refinery feed rate of 65,000 bbl/day x 365 day/yr = 23,725,000 bbl/yr

² Net Emissions Change = Potential Emissions - Baseline Actual Emissions

³ Net Emissions Change = Projected Actual Emissions - Baseline Actual Emissions

Air Quality Assessment:

An Ambient Air Quality Impact Assessment (AAQIA) was not performed on the Crude Flare and FCC Flare stacks, since the net emissions from both flares will be reduced.

Significant Permit Conditions:

Attachment II(A), Special Condition No. B.1 and B.2.

The FCC Flare Vapor Recovery System was added as an affected facility subject to 40 CFR Part 60, Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries. This standard applies to the following facilities in petroleum refineries: compressors and the group of all equipment (e.g., valves, pumps, flanges, etc.) within a process unit in VOC service. The FCC Flare Vapor Recovery System is also subject to 40 CFR Part 60, Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems. This standard applies to the following facilities in petroleum refineries: individual drain systems, oil-water separators, and aggregate facilities.

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Conclusion and Recommendations:

In this significant modification, the FCC Flare will have a Flare Vapor Recovery System added to its operation. This system will recover routinely generated refinery flare gases and deliver them back to the FCC Wet Gas Compressor, where the gases will be compressed and then recovered in various product columns. The remaining gas is sent to the fuel gas treatment.

Recommend issuance of the significant modification to existing Covered Source Permit No. 0088-01-C based on the significant permit conditions shown above. The proposed project will result in a net emissions decrease from the Crude and FCC flares. A 30-day public comment period and a 45-day EPA review period are also required.

Reviewer: Darin Lum
Date: 5/06